BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 140

In the Matter of	)	SUPPLEMENTAL DIRECT
	)	TESTIMONY OF KENDAL C.
Biennial Determination of Avoided Cost	)	BOWMAN ON BEHALF OF DUKE
Rates for Electric Utility Purchases from	)	ENERGY CAROLINAS, LLC, AND
Qualifying Facilities	)	DUKE ENERGY PROGRESS, INC.

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kendal Crowder Bowman. My address is 410 South Wilmington Street, Raleigh, NC 27601.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed as Vice President, Regulatory Affairs and Policy-North Carolina for Duke Energy Carolinas ("DEC") and Duke Energy Progress ("DEP") (collectively the "Companies"), which are wholly-owned subsidiaries of Duke Energy Corporation.

Q. HAVE YOU SUBMITTED TESTIMONY PREVIOUSLY IN THIS PROCEEDING?

A. Yes. I submitted direct testimony in this proceeding on behalf of the Companies. My direct testimony includes a summary of the scope of my employment and my professional and educational background.

Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL DIRECT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my supplemental direct testimony is to respond to issues raised by other parties pertaining to the Commission's process and procedures establishing avoided cost rates for qualified facilities ("QF"). First, I will address the applicability and relevance of the FERC's decision on *Cal. Pub. Util. Comm'n.* 133 FERC ¶ 61,059 (2010) ("CPUC" or "CPUC Clarification Order") and Minnesota's recently-enacted state policy mandating the creation of a value of distributed solar generation ("VOS") methodology as an alternative to net metering in that jurisdiction. Next, I will address whether the standard terms and conditions set in the Commission's biennial avoided cost rate proceedings should be available to QFs with a nominal capacity of up to 10 MW and whether the Commission should require the Companies to offer such terms and conditions for 20-year terms. Additionally, I will explain why injecting externalities such as speculative future environmental costs and alleged societal benefits into the calculation of avoided costs is not consistent with PURPA and is not in the best interest of the State's electric customers. Finally, I will explain why the Commission should not increase the performance adjustment factor ("PAF") for non-hydroelectric QFs to 2.0.

II. FERC'S DECISION IN *CPUC* DOES NOT REQUIRE RADICAL CHANGES IN THE COMMISSION'S AVOIDED COST PROCESS AND DOES NOT BROADEN THE DEFINITION OF AVOIDED COSTS UNDER PURPA

Q. HAS FERC'S *CPUC* DECISION BEEN RAISED BY OTHER PARTIES IN THIS PROCEEDING?

A. Yes, it has, and the Companies would normally address such legal precedent in its brief. However, the manner in which other parties have invoked the *CPUC Clarification Order* warrants discussion of that case that may assist the Commission in addressing the issues raised in this proceeding. Public Staff witness Kirsh suggests that *CPUC* "affords states increased flexibility to set resource-specific rates that offer greater financial support to QFs than would rates based upon the cost of all resources able to sell to the utility."[1] Public Staff witness Kirsch goes on to state that renewable portfolio standards, presumably such as the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard ("REPS"), "raise the possibility of calculating technology specific avoided cost rates."[2] Environmental Defense Fund ("EDF") witness Munns goes further to suggest that *CPUC* would allow the Commission to "calculate the utility's avoided cost for distributed solar resources by determining the utility's cost of acquiring electricity from distributed solar resources."[3]

Q. PLEASE DESCRIBE FERC'S DECISION IN *CPUC.*

A. First, some background is necessary to properly place the *CPUC Clarification Order* in context. In May 2010, the California Public Utilities Commission ("California Commission") filed a request for declaratory order asking FERC to confirm that the Federal Power Act ("FPA") would not preclude the California Commission from implementing California's Waste Heat and Carbon Emissions Reduction Act ("AB 1613"), a newly-enacted feed-in tariff program requiring California investor-owned utilities ("IOUs") to purchase electricity generated by certain Combined Heat and Power ("CHP") generators and delivered to the grid. Importantly, AB 1613 provided that the rates for such purchases by the California IOUs from CHP generators, effectively a wholesale transaction, would be set by the California Commission, not FERC. Although AB 1613 initially was not intended to implement PURPA, the enabling legislation required the California

[1] Public Staff witness Kirsh Direct, at 9-10.
[2] Public Staff witness Kirsh Direct, at 20.
[3] EDF witness Munns Direct, at 7.

Commission to establish rates that left ratepayers financially "indifferent" to the implementation of AB 1613.

In a July 15, 2010 Order,[4] FERC held that it retained exclusive jurisdiction under the FPA over sales for resale of electricity and that any attempt by the California Commission to set a wholesale rate to implement AB 1613 would "constitute impermissible wholesale rate-setting . . . preempted by the FP**A.**"[5] Although the CPUC had not sought approval of its program under PURPA, FERC, on its own initiative, noted that Congress had enacted an exception through PURPA Section 210(a) to its exclusive jurisdiction over setting wholesale rates. FERC suggested that if the rates set by the California Commission under the AB 1613 program meet PURPA's avoided cost requirements (and applied only to QFs), then they would be acceptable under PURPA and would not violate the FP**A.**

The California Commission then sought rehearing and further consideration of the July 15, 2010 Order to confirm that PURPA allowed multi-tiered avoided cost rate structures that would allow California to achieve AB 1613's policy goal of promoting efficient CHP generators through standard energy purchase contracts.

Q. HOW DID FERC RULE IN THE *CPUC CLARIFICATION ORDER*?

[4] *California Public Utilities Commission*, 132 FERC ¶ 61,047 (2010) ("July 15, 2010 CPUC Order"), *clarification granted and reh'g dismissed*, 133 FERC ¶ 61,059 (2010), *reh'g denied*, 134 FERC ¶ 61,044 (2011) ("CPUC Order Denying Rehearing").
[5] *July 15, 2010 CPUC Order*, at P 64.

A. In the *CPUC Clarification Order*, FERC made two key holdings. First, FERC recognized that State Commissions tasked with establishing avoided cost rates may create a "multi-tiered avoided cost rate structure" where a state requires a utility to procure a certain percentage of its energy from generators with certain characteristics.[6]

Second, FERC held that PURPA only allows a State Commission to account for and include "real costs that may incurred by utilities" in determining utility avoided costs.[7] PURPA precludes additional compensation or "adders" for environmental externalities through the avoided cost regime. However, FERC also recognized that "a state may separately provide additional compensation for environmental externalities, outside the confines of, and, in addition to the PURPA avoided cost rate, through the creation of renewable energy credits (RECs)."[8]

Q. DOES THE *CPUC CLARIFICATION ORDER* STAND FOR THE PROPOSITION ASSERTED BY PUBLIC STAFF WITNESS KIRSH AND EDF WITNESS MUNNS?

A. Not entirely. Both of these witnesses seem to presume that the *CPUC Clarification Order* expands the NCUC's authority to increase avoided cost rates for certain QFs. To the contrary, this Order reaffirms that a state commission's discretion on setting avoided costs rates is limited to the inclusion of real costs actually incurred by the purchasing utility. Provided that this limitation is not

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[6] *CPUC Clarification Order*, at P 26-27.
[7] *CPUC Clarification Order*, at P 31.
[8] *CPUC Clarification Order*, at P 31.

violated, FERC recognized that segmenting avoided cost rate by technology may be appropriate under certain state policies. However, such segmentation is certainly not required and is a matter clearly left to the discretion of the State Commissions.

Q. DID THE *CPUC CLARIFICATION ORDER* MANDATE A CHANGE IN HOW THE NORTH CAROLINA COMMISSION SETS AVOIDED COST RATES?

A. No, in my view, it does not. The same statutory requirements continue to control. Rates established to implement PURPA must be: (1) just and reasonable to electric consumers and in the public interest; (2) not discriminatory against QFs; and (3) not in excess of "the incremental cost to the electric utility of alternative electric energy."[9] While *CPUC* acknowledged conceptually that a segmented avoided cost framework could be consistent with Section 210 of PURPA and FERC's regulations (assuming state policies clearly mandate utilities to purchase energy from generators with certain characteristics), FERC did not direct State Commissions how to establish avoided cost rates. To the contrary, FERC reiterated that State Commissions are afforded a "wide degree of latitude in establishing an implementation plan for section 210 of PURPA, as long as such plans are consistent with our regulations."[10] On rehearing of the *CPUC Clarification Order*, FERC reiterated that "while [FERC] provided guidance on the concept presented by the [California Commission], states may have other ways of establishing avoided cost rates that may be consistent with the [FERC]'s

[9] 16 U.S.C.S. § 824a-3(b); 18 C.F.R. 292.304(a)(1).
[10] *CPUC Clarification Order*, at P 24.

PURPA regulations."[11] In all instances, such determinations are fact specific to the energy policies and purchase mandates existing in a given jurisdiction.

Q. DO YOU BELIEVE THAT *CPUC* WAS INTENDED TO PROVIDE STATE COMMISSIONS WITH THE ABILITY TO PROVIDE RENEWABLE QFS WITH GREATER FINANCIAL SUPPORT?

A. No, I do not. FERC made clear that its decision did not alter the fundamental requirement that all the utility customers be kept financially indifferent as to whether the utility purchases power from a QF, purchases it from another source, or generates the power itself. FERC noted that to the extent that the AB 1613 program kept California ratepayers financially indifferent, the program could be squared with PURPA's avoided cost regime.[12] Thus, even where state energy policies could support segmentation of avoided cost rates, the state-established rates cannot exceed the "incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility…, such utility would generate itself or purchase from another source."[13]

It is also extremely important to understand that the *CPUC Clarification Order* did not expand the PURPA avoided cost concept to include the "renewable value" or "renewable benefits" of a given resource, even where a state has enacted a renewable energy procurement requirement. State renewable energy programs that provide compensation for environmental externalities through RECs are

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[11] *CPUC Order Denying Rehearing*, at P 36.
[12] CPUC *Order Denying Rehearing*, at P 36.
[13] *CPUC Clarification Order*, at P 23 *citing* 18 C.F.R. § 292.101(b)(6).

"outside of PURPA and . . . not part of the avoided cost calculation."[14] FERC has explained both before and subsequent to the *CPUC Clarification Order* that "avoided costs in short are not intended to compensate the QF for more than capacity and energy."[15] Thus, while states may have authority to compensate QFs for environmental benefits and other externalities through a State-imposed renewable energy procurement program or REC requirement, such compensation must be provided outside of the PURPA avoided cost process.

Q. GIVEN NORTH CAROLINA'S RENEWABLE POLICIES, DO YOU BELIEVE THAT *CPUC* SUPPORTS INCREASED AVOIDED COST RATES FOR ANY SPECIFIC CATEGORIES OF RENEWABLE QFS?

A. No. The REPS enacted by the General Assembly through Session Law 2007-397 ("Senate Bill 3") is designed to be self-contained and not to impact avoided cost calculations. While the REPS requires the State's electric power suppliers to procure increasing percentages of energy from a broad spectrum of renewable energy technologies over the next decade, the "renewable value" or "incremental cost" associated with these procurement requirements is captured through RECs. These RECs represent the commoditization of the non-energy and non-capacity value of renewable resources and are "incremental to" or "in excess of" a utility's avoided costs.[16] Thus, unlike California's AB 1613 program, which was focused on valuing the capacity and energy of CHP generators, North Carolina's REPS policy is focused on capturing the incremental renewable costs of certain

[14] *CPUC Clarification Order*, at P Fn 62 *citing American Ref-Fuel*, 105 FERC ¶ 61,004 at P 23.
[15] *Morgantown Energy Associates*, 140 FERC ¶ 61,223 (2012) at P 8 *citing American Ref-Fuel*, 105 FERC ¶ 61,004 at P 20.
[16] *See* N.C.G.S. § 62-133.8(h)(1).

generators in excess of avoided costs and, therefore, should not impact avoided costs derived under PURPA.

Stated another way, to the extent certain generating facilities offer environmental or societal benefits, over and above the energy and capacity that they provide, North Carolina's REPS policy provides for such facilities to be compensated for those characteristics by the sale of RECs. A renewable resources' RECs are sold separately from the power that the resources produce. Therefore a renewable QF (such as a solar QF) may sell capacity and energy to a utility at avoided cost rates and then may choose to sell the RECs associated with that power to the same utility or another party for additional compensation. If the Commission established segmented avoided cost rates in order to encompass the beneficial attributes of certain QFs that are already reflected in the QFs RECs, the QF would be compensated twice for those attributes – once through the expanded avoided cost rates and again when it sells its RECs. This would force utility customers to pay twice for a renewable QF's environmental attributes. That result is not what was intended under Senate Bill 3 or PURPA.

III. MINNESOTA'S VALUE OF SOLAR ("VOS") METHODOLOGY IS NOT AN APPROPRIATE TEMPLATE FOR THE COMMISSION'S AVOIDED COST RATE-SETTING

Q. WHAT IS YOUR UNDERSTANDING OF MINNESOTA'S RECENTLY DEVELOPED VOS METHODOLOGY FOR DISTRIBUTED SOLAR FACILITIES?

A. EDF witness Munns, North Carolina Waste Awareness Network ("NC WARN") witness LaPlaca, and Public Staff witness Brown all note the recent VOS methodology developed by the Minnesota Department of Commerce ("DOC"). In 2013, the Minnesota legislature enacted legislation directing the Minnesota DOC to develop a distributed solar value methodology as an alternative to the Minnesota IOUs' net metering tariff option. Specifically, the statute directed the DOC to create a "bill credit mechanism for the value to ***the utility, its customers, and society*** for operating distributed photovoltaic resources interconnected to the utility system and operated by customers primarily for their own energy needs." [17] As directed by the VOS legislation, on April 1, 2014, the Minnesota Public Utilities Commission reviewed the Department of Commerce's VOS methodology and approved it as consistent with the Minnesota legislature's intent.[18]

Q. ARE THERE DISTINCTIONS THAT SHOULD BE MADE BETWEEN A STATE-DEVELOPED VOS METHODOLOGY AND AVOIDED COST RATES UNDER PURPA?

A. Yes, there are a number of key distinctions that make the VOS methodology inappropriate for establishing avoided costs under PURP**A.** The most obvious distinction is that Minnesota VOS methodology was designed for a different purpose – to achieve state policies through quantifying and capturing the value of

[17] Minn. Stat. 216B. 164 Subd. 10(a) (emphasis added).
[18] *Order Approving Distributed Solar Value Methodology*, Minnesota Public Utilities Commission Docket No. E-999/M-14-65 (April 1, 2014).

distributed solar energy resources to "the utility, its customers, and society."[19] Minnesota's legislation provides that the VOS methodology must, among other things, account for the "environmental value" of the customer-owned solar installations and may also incorporate an array of other values and factors. The VOS methodology captures Minnesota's assessment of the full value of distributed solar to the utility, its customers, and society by including asserted environmental and social costs in addition to avoided energy and capacity costs, for example, the Minnesota VOS methodology's inclusion of an avoided "social cost of carbon" as part of the value of distributed solar.[20]

As noted above, the value of environmental externalities of distributed solar (or any other PURPA eligible resource), as assessed pursuant to an explicit State policy mandate, are separate and distinct from the energy and capacity avoided costs to the utility captured by PURP**A.** The Minnesota legislature provided clear direction that the VOS methodology must value and include compensation to distributed solar generators for these "renewable benefits." Therefore, the VOS methodology – based in state policy – includes compensation for factors that are irrelevant to and outside the scope of the Commission's avoided cost determination under PURP**A.**

Q. DO YOU BELIEVE THAT MINNESOTA'S VOS METHODOLOGY PROVIDES AN APPROPRIATE TEMPLATE FOR NORTH CAROLINA'S IMPLEMENTATION OF PURPA?

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[19] Minn. Stat. 216B. 164 Subd. 10(a).
[20] *See* witness Munns Direct, Exhibit 1 (*Minnesota Value of Solar: Methodology*, at 40, fn 21)

A. No, it does not. Minnesota used a VOS study for purposes that are distinct to that State's policy directive and irreconcilable with the purpose of and limitations of the PURPA avoided cost process. If anything, a review of the Minnesota program highlights why VOS is not an appropriate means of setting avoided cost rates. Thus, while a VOS may be useful in the context of a state-established policy designed to go beyond avoided cost, it is not appropriate for use for setting avoided cost rates under PURP**A.**

Moreover, the Minnesota policy was designed to support and encourage a very specific type of resource – i.e., small solar installations installed by customers primarily for their own energy needs.[21] Conversely, PURPA applies to all QFs up to 80 MW and, in the case of solar QFs in North Carolina, applies to thousands of MW of proposed solar QF projects. There is no logic in the suggestion that the Commission should alter its avoided cost process based on Minnesota's policy designed to encourage a limited and specific class of projects and which was expressly designed to go above and beyond avoided costs, which unambiguously establish the absolute statutory ceiling for QF compensation under PURP**A.** For the foregoing reasons, the VOS methodology developed by Minnesota is not an appropriate means of establishing avoided cost rates under PURPA and the nation.

[21] Minn. Stat. 216B. 164 Subd. 10(d).

IV. THE ELIGIBILITY CAP FOR STANDARD RATES, TERMS AND CONDITIONS SHOULD NOT BE INCREASED TO 10 MW

Q. DO YOU AGREE THAT THE STANDARD TERMS AND CONDITIONS SHOULD BE OFFERED TO QFS WITH A MAXIMUM CAPACITY OF 10 MW?

A. No. As explained in my testimony and the direct testimony of DEC and DEP witness Snider filed previously in this proceeding, the Companies believe that the goals of PURPA and the public interest would be better served by reducing the eligibility cap for standard terms and conditions to 100 kw.[22] As witness Snider explained, the biennial process for establishing avoided cost rates results in application of the same rates to QFs even if they are put in service years apart. The effect of the imprecision inherent in that process would be mitigated by limiting the availability of those rates to smaller projects. Conversely, raising the eligibility cap simply exacerbates the problem by making more projects eligible for the standard avoided cost rates.

Q. WOULD INCREASING THE MAXIMUM CAPACITY CAP RESULT IN A FURTHER INCREASE IN QF GENERATION IN NORTH CAROLINA?

A. Based on the testimony of North Carolina Sustainable Energy Association ("NCSEA") witnesses Cohen and Hanes (as substituted for Ness), one might assume that increasing the eligibility cap for standard avoided cost rates would increase the already extraordinary amount of QF generation proposed for North Carolina. Both witnesses Cohen and Hanes acknowledge that raising the

[22] DEC/DEP witness Bowman Direct, at 16-20; DEC/DEP witness Snider Direct at 43-46.

eligibility cap would make it easier for developers to build larger QF facilities.[23] NCSEA witness Hanes attempts to deflect this issue by arguing that extending the standard avoided cost rates to larger QFs would not increase the number of new projects, it would simply make it easier for projects that were already feasible to be built.[24] Witness Hanes' argument, however, cannot be squared with her own testimony in which she suggests that larger facilities are more profitable for developers due to economies of scale and that QF developers would pursue such projects if they could do so under standard terms and conditions.[25] If true, increasing the eligibility cap for standard avoided cost rates would lead developers to increase the size of their projects significantly. Thus, even if the number of proposed projects did not change, the net effect would be an enormous increase in the amount of proposed QF capacity, which would have the same effect on customers as the "onslaught of development" that witness Hanes argues would not occur.[26]

Q. WOULD INCREASING THE MAXIMUM CAPACITY CAP BE CONSISTENT WITH PURPA'S PURPOSE OF ENCOURAGING DEVELOPMENT OF QFS?

A. No. PURPA is intended to support the development of QFs. However, it is not intended to encourage such development at all costs, nor is it intended as a means to make any and all QFs viable. While making the standard avoided cost rates available to larger QFs may make it easier to develop such facilities, it will do so

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[23] NCSEA witness Cohen Direct at 10; NCSEA witness Hanes Direct at 9.
[24] NCSEA witness Hanes Direct at 9.
[25] NCSEA witness Hanes Direct at 8-9.
[26] NCSEA witness Hanes Direct at 8-9.

by expanding the use of avoided cost rates that are set only every two years. The practical limitations of that biennial process already creates a certain degree of imprecision in setting avoided cost rates by applying the same rates to projects even though they are placed in service months or even years apart. Necessarily, during the intervening time, circumstances change that impact a utility's avoided cost, often dramatically. Thus, despite the parties' and the Commission's best efforts, the biennial avoided cost rate process results in the application of rates that do not precisely reflect a utility's current avoided cost results to multiple projects. While this may be an unavoidable consequence of having to offer standard terms and conditions for certain QFs, raising the eligibility cap for standard avoided cost rates exacerbates the issue and would take the Commission's policies further from the intent of PURPA, not closer to it.

Q. WOULD INCREASING THE MAXIMUM CAPACITY CAP BE CONSISTENT WITH THE COMMISSION'S PREVIOUSLY STATED POLICIES FOR ESTABLISHING AN ELIGIBILITY CAP FOR STANDARD TERMS AND CONDITIONS?

A. No, it would not. PURPA and FERC regulations only require that standard terms and conditions be available to QFs of 100 kw or less.[27] FERC established that requirement based in large part on its desire to prevent small QF projects from being burdened with disproportionate transaction costs.[28] Similarly, in Docket E-

[27] 18 C.F.R. 292.304(c).

[28] Order No. 69, FERC Stats. & Regs., Regs. Preambles 1977-1981 P30, 128 at 52 (1980) (adopting 100 kW standardized rate for purchase, an increase from 10 kW included in proposed rules, in order to avoided unduly burdensome transaction costs on small generators).

100, Sub 41A, the Commission established the current eligibility limit for standard avoided cost rates based on the view that developers of smaller projects may not have the "resources or the expertise to negotiate a contract with a utility."[29] Such policy concerns are simply not as relevant in the context of larger QF projects. Given the cost and complexity of developing such facilities, any developer that intends to construct a QF facility that is 5 MW or larger will undoubtedly be more sophisticated and well-informed. Moreover, the transaction costs associated with bilateral negotiations would be small compared to the overall cost of the QF project. Thus, the policy rationale for requiring standard terms and conditions for certain QFs is inapplicable to the large-scale projects to which some parties wish to apply it.

Q. WOULD INCREASING THE ELIGIBILITY CAP FOR STANDARD TERMS AND CONDITIONS TO 10 MW BE IN THE PUBLIC INTEREST?

A. No, it would not. Increasing the eligibility cap for standard avoided cost rates will simply apply a less than precise avoided cost rate to a much larger amount of QF capacity. Such a result would not be in the public interest, and the only beneficiaries of such a change in policy would be the QF developers themselves. NCSEA witnesses Cohen and Hanes both claim that constructing larger QFs would be more cost effective. However, none of the alleged resulting cost savings would inure to the benefit of customers because the rates paid to QFs (and borne by the Companies' customers) are based on the Companies' avoided costs,

[29] *Order Establishing Levelized Rates and Cogenerated Power and Maintaining Interconnection and Wheeling Prices,* at 12 Docket No. E-100, Sub 41A (Jan. 22, 1985).

not the cost incurred by the developers to construct the QF facility. Consequently, facilitating the construction of larger QFs would only serve to improve the developers' profit margins, with no actual benefit to the Companies' customers. If, in fact, it is more cost-effective for QF developers to construct facilities of more than 5 MW, then the developers are free to pursue such projects all the way up to the 80 MW cap set by PURP**A.**

V. <u>THE MAXIMUM STANDARD CONTRACT TERM SHOULD NOT BE EXTENDED TO 20 YEARS</u>

Q. SHOULD THE COMMISSION EXTEND THE MAXIMUM STANDARD CONTRACT TERM FROM 15 TO 20 YEARS?

A. No. Since 1996, the Commission's policy has been that the Companies should offer 5-, 10- and 15-year contracts to hydroelectric QFs and certain renewable QFs of less than 5 MW. Over time, the category of renewable, non-hydroelectric QFs eligible for such long-term contracts has been expanded. Initially, it included only QFs that derive fuel from trash or methane from landfills or hog waste.[30] The eligibility for the long-term contracts was later expanded in 2003 to include QFs fueled by poultry waste[31] and then in 2005 further expanded to include solar, wind and non-animal forms of biomass.[32] The advocates for extending the maximum of these contracts have not provided any valid reason for their proposal.

[30] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, at 9-11, 24 Docket No. E-100, Sub 79 (June 19, 1997).

[31] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, at 9-12, 37 Docket No. E-100, Sub 96 (Oct. 29, 2003)("2003 Avoided Cost Order").

[32] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, at 6-11, 51-52 Docket No. E-100, Sub 96 (Sept. 29, 2005) ("2005 Avoided Cost Order").

Q. WHAT HAS THE COMMISSION STATED IN THE PAST ABOUT THE LENGTH OF THE STANDARD CONTRACTS?

A. The issue of whether the Commission's policy on standard QF contract length should be changed has come up in several biennial avoided cost proceedings. The Commission consistently has recognized that this issue warrants regular re-evaluation in light of changing circumstances.[33] Most importantly, the Commission has recognized that this issue requires balancing the desire to encourage the development of certain types of QFs against the risks and burdens that long-term contracts place on customers.[34] In particular, the Commission has observed that long-term QF contracts pose a risk of stranded costs and overpayments on utility customers, particularly given the challenges of accurately predicting a utility's avoided cost over a long period of time.[35]

Q. DOES PURPA REQUIRE A MAXIMUM STANDARD CONTRACT TERM OF 20 YEARS?

A. No, it does not. PURPA allows for, but does not require, that QFs be offered long term contracts. However, it should be noted that N.C.G.S. § 62-156(b)(1) states that QF development should be encouraged through the availability of "long-term contracts." However, the North Carolina statutes do not define the phrase long term contract and certainly in the typical parlance of the utility industry "long term" refers to contract terms that are far less than 20 years.

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[33] *See e.g., Order Establishing Standard Rates & Contract Terms for Qualifying Facilities*, at 11 Docket No. E-100, Sub 136 (Feb. 21, 2014).
[34] *Id.*
[35] *Id.*

Q. WOULD INCREASING THE MAXIMUM STANDARD CONTRACT TERM TO 20 YEARS BE IN THE PUBLIC INTEREST?

A. No, it would not. As the Commission has correctly observed, long term QF contracts impose risks on public utilities and their customers by locking them into purchased power costs based on long term projections of costs. These risks are particularly acute in terms of energy cost projections, which are difficult to project accurately over an extended time period. Long term avoided cost rate contracts typically assume that energy costs continue to escalate unabated over the entire term of the contract. In the context of long-term contracts, the effect of such assumed escalation results in rates that assume that future energy costs will always be much higher than current energy costs. Of course, that is not always the case, and when energy costs do not rise in that fashion, the rates paid to the QF will exceed the purchasing utility's true avoided cost.

The Companies and their customers already bear this risk in the context of –the long-term contracts that must be offered to QFs. Increasing the maximum term of such contracts to 20 years or more, as proposed by certain parties, only serves to increase such risks. Moreover, the effect of the escalation assumed in avoided energy cost projections becomes more pronounced as the term of the contract increases.

Simply put, long term avoided cost projections are never entirely accurate, but the longer the term of the projection, the more inaccurate they are likely to be. Thus, increasing the maximum term of standard QF contracts will necessarily push the avoided cost rates paid to QFs further away from the purchasing utility's true avoided costs and will increase the risk that the utility's customers will bear costs in excess of the utility's avoided cost.

There is no legitimate reason that would justify requiring utilities and their customers to incur the additional risks and adverse effects of requiring even longer terms for standard QF contracts. As I have testified previously in this proceeding, the empirical evidence shows that QF development in North Carolina is extraordinarily robust and shows no signs of decreasing.[36] Thus, in terms of balancing the need to encourage QF development against the risks associated with longer term contracts, there is no question that risks of 20-year standard QF contracts far outweigh the "benefits" associated with encouraging even greater QF development.

Q. HOW DO YOU RESPOND TO THE ARGUMENTS OF NCSEA WITNESSES COHEN AND BEACH THAT THE COMMISSION SHOULD EXTEND THE MAXIMUM TERM OF THE STANDARD CONTRACT TO 20 YEARS IN ORDER TO ALIGN THE CONTRACT TERM WITH THE USEFUL LIFE OF SOLAR FACILITIES?

A. NCSEA's witnesses both argue that a 20-year standard term QF contract would better match the expected 20-year useful life of solar facilities.[37] Witness Beach suggests that if a solar QF enters into a 15-year contract, it is disadvantaged because it would have to enter into a subsequent 5-year contract to cover its entire

[36] DEC/DEP witness Bowman Direct, at 13-14.
[37] NCSEA witness Cohen Direct, at 6; NCSEA witness Beach Direct, at 33.

20-year useful life.[38] These arguments fail to justify their proposal to increase the maximum term for standard QF contracts for several reasons.

Over a 20-year period, a 15-year contract and a 5-year contract will more accurately reflect a utility's avoided cost than a single 20-year contract. Even the best avoided cost projections will deviate from a utility's true avoided cost over a 20-year period. This is obviously also true for 15-year projections, and "resetting" the avoided cost payments based on a shorter 5-year contract certainly would mitigate such inaccuracies when viewed for the entire 20-year period. Thus, regardless of whether it ends up being a benefit or detriment to the QF, a 15-year contract followed by a 5-year contract would better achieve the core principle of PURPA that QFs should receive payments that are no more than the purchasing utility's avoided cost.

Moreover, PURPA certainly provides no basis for the arguments by NCSEA witnesses Beach and Cohen. PURPA does, however, prohibit discrimination among QFs.[39] If the Commission accepted the proposition that a QF's useful life should define the term of the standard contract that is offered to them, it would follow that trash burning and biomass QFs with useful lives of 30 to 40 years should be offered standard contracts of commensurate length. Clearly, that would not be in the public interest and illustrates why the proposal to set the contract term for QFs based on their useful lives is without merit.

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[38] NCSEA witness Beach Direct, at 33.
[39] 18 C.F.R. 292.304(a)(1)(ii).

Q. HOW DO YOU RESPOND TO THE ARGUMENTS OF SOUTHERN ALLIANCE FOR CLEAN ENERGY ("SACE") WITNESS RABAGO THAT THE COMMISSION SHOULD EXTEND THE MAXIMUM TERM OF THE STANDARD CONTRACT TO 20 YEARS TO MAKE THEM CONSISTENT WITH POWER PURCHASE AGREEMENTS TYPICALLY ENTERED INTO BY UTILITIES?

A. SACE witness Rabago's argument is wrong for several reasons. He assumes that utilities regularly enter into 20- to 25-year fixed energy price contracts.[40] This is not the case. To the contrary, my experience is that utilities rarely, if ever, enter into power purchase agreements ("PPAs") of such length. Moreover, whenever a utility does enter into PPA of any significant duration (i.e., one year or more), it will tie energy costs to actual energy market prices either by providing the fuel itself through a tolling arrangement or linking the energy rates under the PPA to a market index. The Companies have, under very limited circumstances, entered into longer term fixed price contracts to meet the State's animal waste set aside compliance requirements under Senate Bill 3. These contracts, that also included significant REC payment components, were entered into to support very high risk project development of animal waste solutions. These contracts are very much the exception, not the rule, and were driven by policy mandates, not prevailing market conditions. Thus, the Companies' power purchasing practices, to the extent that they are relevant at all, suggest that QF contracts should be shorter, not longer.

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[40] SACE witness Rabago Direct, at 18.

Q. NCSEA WITNESSES COHEN AND HANES ALSO ARGUE THAT THE COMMISSION SHOULD EXTEND THE MAXIMUM TERM OF THE STANDARD CONTRACT TO 20 YEARS TO REDUCE THE COST OF FINANCING AND DEVELOPING QFS. WHAT IS THE COMPANIES' RESPONSE TO THIS ARGUMENT?

A. Unlike public utilities, QF developers are not required to make their financial and operating costs public. Although it seems counter intuitive that longer term financing will decrease financing costs, it is not possible to test the accuracy of the assertions of NCSEA witnesses Cohen and Hanes that longer contract durations equate to lower financing costs for QF developers.[41] Even if their claims are accurate, however, the benefit to such developers does not justify mandating 20-year standard QF contracts because such benefits would inure exclusively to those developers, while the increased risk relating to the longer term would be borne exclusively by the Companies' customers.

Increasing the maximum term of standard QF contracts to 20 years will increase the risks that customers bear for such contracts. Such increased risk surely outweighs the modest financial benefits that witnesses Cohen and Hanes attribute to longer term contracts. It seems illogical to assume that reduced financing costs of 3-5% would make a significant difference in the rate of QF development in North Carolina. A more likely scenario is that, if the Commission acceded to witness Cohen's and witness Hanes' proposal, the same QF projects will be developed, but the developers will benefit from the lowered financing

[41] NCSEA witness Cohen Direct, at 5; NCSEA witness Hanes Direct, at 5.

cost. In that regard, it is important to remember that lowering the development costs of QFs benefits the QF developers only; the purchasing utility's and their customers continue to bear the burden of paying the QFs the utility's full avoided cost. Therefore, witnesses Cohen and Hanes are essentially proposing that the Commission impose additional risks on utilities and their customers through longer term standard contracts so that QF developers can obtain improved profit margins. This is not a proposal that is in the public interest, but again simply in the best interest of NCSEA's members and their investors.

Witness Cohen attempts to bolster his position by arguing that providing QFs the benefit of more favorable financing costs is appropriate in order to offset the potential effects of the expiration of current tax incentives.[42] NCSEA witness Hanes echoes that sentiment, adding that the lowered financing costs would help offset the lowered market prices QFs are receiving for RECs. These arguments are red herrings. State (and federal) policy makers may choose to implement measures to encourage or subsidize QF development outside of the limits of PURP**A.**[43] The North Carolina General Assembly has chosen to do so by providing tax incentives and enacting the REPS, which provides the framework under which RECs may be used to fulfill the REPS requirements. However, the presence or absence of such QF benefits are irrelevant to the implementation of PURPA and in no way diminish PURPA's fundamental principle that rates established under PURPA shall be no more than the purchasing utility's avoided cost.

[42] NCSEA witness Cohen Direct, at 5.
[43] NCSEA witness Hanes Direct, at 5.

If the General Assembly elects to allow the tax incentives currently enjoyed by QFs to expire, it would be inappropriate for the Commission to effectively undo that policy decision by manipulating the avoided cost process to increase QFs' profit margins to offset the loss of the tax incentives. Moreover, the price of RECs is a result of current market forces (e.g., the number of RECs that are available) and the way in which Senate Bill 3 is structured. If the market price of RECs had decreased, any corrective action (assuming that any corrective action is in fact warranted) is the province of the General Assembly. It certainly is not a matter that should affect the way in which the Commission administers the avoided cost process under PURPA. It would have been just as inappropriate for the Commission to adjust avoided cost calculations downward when the tax incentives and Senate Bill 3 were implemented to account for the fact that QFs would be obtaining those benefits. The issues raised by witnesses Cohen and Hanes are wholly outside the scope of PURPA and should play no part in the Commission's administration of the avoided cost process.

Q. YOU HAVE INDICATED THAT YOU DO NOT AGREE WITH TESTIMONY IN SUPPORT OF EXTENDING THE MAXIMUM STANDARD CONTRACT TERM TO 20 YEARS. DO YOU AGREE WITH DOMINION NORTH CAROLINA POWER WITNESS WILLIAMS THAT STANDARD CONTRACT TERMS SHOULD INSTEAD BE LIMITED TO 10 YEARS IN DURATION?

A. I do, for the reasons given by the Companies' witness Snider in his Supplemental Direct Testimony.

VI. EXPANDING THE DEFINITION OF AVOIDED COSTS TO INCLUDE EXTERNALITIES - SUCH AS FUTURE ENVIRONMENTAL COSTS AND ALLEGED SOCIAL BENEFITS - IS NOT CONSISTENT WITH PURPA NOR IN THE BEST INTERESTS OF THE STATE'S ELECTRIC UTILITY CUSTOMERS

Q. HOW ARE AVOIDED COSTS DEFINED UNDER PURPA?

A. Under PURPA, a utility's avoided costs are the "incremental cost of alternative electric energy."[44] The "incremental cost of alternative electric energy" is defined as "the cost to the electric utility of the electric energy which, but for the purchase from the QF, such utility would generate or purchase from another source."[45] PURPA also mandates that no rule implementing PURPA shall provide for a rate that exceeds the incremental cost to the electric utility of alternative electric energy.

Q. WHAT IS THE COMMISSION'S AUTHORITY IN SETTING AVOIDED COST RATES UNDER THIS DEFINTION?

A. Under PURPA, the regulatory bodies that administer the avoided cost process at the state level have considerable discretion in how avoided cost rates are set. Accordingly, the avoided cost processes vary considerably from state-to-state. However, regardless of such variations, the guiding principle remains constant – rates paid to QFs under PURPA may not exceed the purchasing utility's avoided

[44] 16 U.S.C. § 824a-3(b).
[45] *Id.*

cost. The necessary corollary to that principle is that avoided costs can only include costs actually avoided when the utility purchases power from a QF.

Q. DOES PURPA ALLOW FOR THE INCLUSION OF EXTERNALITIES OR SPECULATIVE AVOIDED COSTS?

A. No. The inclusion of such costs in the avoided cost calculation is antithetical to the fundamental principles of PURP**A.**

Q. **SEVERAL WITNESSES HAVE RECOMMENDED INCLUDING VARIOUS FACTORS, WHICH CAN BE BROADLY CHARACTERIZED AS SOCIETAL BENEFITS AND/OR SPECULATIVE FUTURE COSTS, IN AVOIDED COSTS CALCULATIONS THAT HAVE NOT BEEN INCLUDED PREVIOUSLY. WHAT IS YOUR RESPONSE TO THESE RECOMMENDATIONS?**

A. The specific recommendations made by various parties are addressed by witnesses Snider and Makovich. Therefore, I will limit my testimony to general observations at this time.

Although some witnesses are fairly transparent in their arguments[46], most of the parties advocating an expansion of the "avoided cost" use catch phrases that are nominally in line with PURPA, such as a "comprehensive methodology" to establish avoided cost rates.[47] However, when the specifics of their proposals are examined, it becomes clear that the common theme is that they are asking the

[46] *See e.g.,* NC WARN witness LaPlaca Direct, at 4 (asking Commission to "recognize that the near-zero water use of solar, zero risk of fuel cost increases, zero toxic emissions, zero waste storage costs, and 25-30 year panel life provide tangible, measurable value to North Carolina's ratepayers"); TASC witness Smart at 12-13 (suggesting that "societal" benefits of distributed solar generation be included by the Commission).
[47] *See, e.g.,* EDF witness Munns Direct, at 2.

Commission to stretch the definition of avoided costs beyond the bounds established by PURPA in order to increase the rates paid to QFs.

Most of the arguments to broaden the Commission's application of avoided costs in this docket are made in the context of supporting the development of solar QFs.[48] The overarching theme of these proposals is that solar is superior to traditional, fossil-fueled generation from an environmental and societal perspective.[49] The Companies do not dispute that solar generation has beneficial attributes and that such generation has an important role to play in providing electric service to our customers. The same can be said for other renewable resources, such as hydroelectric generation and wind. However, in the context of the current proceeding, the proposals to monetize those benefits as part of a utility's "avoided cost" are inconsistent with PURP**A.**

Additionally, the suggestion that the beneficial attributes of solar generation should be included in the calculation of avoided cost rates runs contrary to the provisions of Senate Bill 3. In establishing the REPS requirement in Senate Bill 3, the General Assembly set a cap on the "incremental cost" that customers should bear for REPS compliance. That cost is defined as the cost in excess of a utility's "avoided cost." Thus, the General Assembly understood that a utility may need to pay more than its avoided cost in order to obtain renewable energy or RECs to comply with Senate Bill 3, and the General Assembly consciously chose to limit the amount of such cost that a utility and its customers

[48] *See e.g.*, NC WARN witness LaPlaca Direct, at 4-13; SACE witness Rabago Direct, at 15-20; EDF witness Munns Direct, at 6-10; TASC witness Smart Direct, at 12.
[49] *Id.*

would be required to incur. If the Commission incorporates the value of the renewable attributes of QFs into the calculation of avoided costs, it will have effectively folded Senate Bill 3's "incremental costs" of renewable resources into avoided cost, effectively undermining Senate Bill 3's incremental cost cap.[50] As I explained in discussing FERC's *CPUC* decision, incorporating such factors into avoided cost rates effectively double counts them – once in avoided cost rates and once as part of the REC. The intent of these parties' recommendation is simply to establish a more favorable avoided cost rate for certain QFs (particularly solar QFs), not to develop a more accurate calculation of avoided costs.

Q. WHY IS CONSIDERATION OF SPECULATIVE, FUTURE COSTS IN THE AVOIDED COST PROCESS INAPPROPRIATE UNDER PURPA?

A central principle of PURPA is that avoided costs should include only energy and capacity costs that a utility ***actually*** avoids when it purchases power from a QF.[51] Including speculative costs that may or may not arise in the future violates this principle. To be clear, I am not referring to projections regarding the future level of currently known and measurable costs. The long-term nature of QF contracts requires such projections. However, including costs associated with factors which have not and may never come to pass cannot be squared with PURPA.

It is important to remember that the purpose of the avoided cost principle in PURPA is to protect customers from paying more for electricity than they otherwise would as a result of a utility purchasing power from a QF. In the case

[50] N.C.G.S. § 62-133.8(h)(4).
[51] *CPUC Clarification Order*, at P 31.

of costs associated with potential future carbon regulations, the regulations may not ever be implemented, or they may be implemented later than currently anticipated, or the costs of compliance may be substantially lower than anticipated. In any of these cases, the costs reflected in avoided cost rates will be higher than the utility's actual avoided cost rates, violating both the letter and spirit of PURP**A.**

Moreover, opening the avoided cost rate process to speculation about future costs would make the process unworkable. If the Commission were to consider conjecture regarding the cost of compliance with future environmental laws and regulations, it would have to consider a host of other speculative factors. Expecting the discussion to involve such theoretical factors will make the avoided cost process a morass, with each party presenting a host of abstract factors making it impossible to accurately define factors designed to produce an avoided cost rate that best serves its purposes.

Third, if a QF is concerned that the advent of future circumstances, such as new environmental compliance requirements, will cause a substantial increase in future utility avoided costs, the QF can address that concern itself. The QF has the option of entering into long term contracts at the utility's current avoided cost rate or entering into shorter term contracts. If a QF is convinced that the cost of future environmental laws and regulations will increase in the future, it can enter into a shorter term contract and then enter into a longer term contract if and when such future environmental requirements are actually in place. In essence, QFs in this case want it both ways. They want QFs to have the benefit of locking into long term contracts and have the Commission layer onto the avoided cost calculation the cost of speculative future costs in addition to the utility's current avoided costs. Such an approach is without merit and inconsistent with PURPA.

Q. WHAT CONCLUSIONS HAVE YOU DRAWN BASED ON YOUR REVIEW OF THE PROPOSALS PUT FORWARD BY OTHER PARTIES IN THIS DOCKET?

A. The majority of the non-utility parties in this case are strong advocates for solar generation. Although some have a vested financial interest in the success of the solar industry in North Carolina, most appear to favor solar generation based on its environmental attributes. As a result of their desire to support solar development to the utmost, they have proposed that the Commission take steps that go far beyond the bounds set by PURPA for setting avoided cost rates. Specifically, they suggest that the Commission attempt to quantify every alleged benefit of solar generation, no matter how speculative, and treat such benefits as avoided costs. Although solar generation has many positive characteristics, the Companies cannot agree with proposals that would violate limits of PURPA and impose additional costs on their customers. This is particularly true given that North Carolina's REPS policy clearly indicates that such beneficial attributes of renewable generation are to be addressed outside of the avoided cost process. The Commission, therefore, should reject the suggestions to expand the scope of avoided cost calculations to include such considerations.

Q. SHOULD THE COMMISSION DIRECT THE COMPANIES' USE VALUE OF SOLAR ("VOS") STUDIES IN CALCULATING AVOIDED COST RATES?

A. No, a VOS study asks the wrong question for avoided cost purposes under PURP**A.** A VOS study proceeds from the premise that every benefit that can be derived from or attributed to solar generation should be categorized and quantified. The result is a catalogue of alleged solar benefits, many of which are irrelevant to avoided costs calculations and inappropriate for use in avoided cost rates.

Q. ARE YOU AWARE OF ANY STATE COMMISSION THAT HAS SET AVOIDED COST RATES PURSUANT TO A VOS ANALYSIS?

A. No. I understand that some state commissions have used a VOS study approach for other purposes such as establishing alternatives to net metering tariffs, but I am not aware of any case in which a state commission has set avoided cost rates under PURPA pursuant to a VOS study.

VII. THE PERFORMANCE ADJUSTMENT FACTOR SHOULD NOT BE INCREASED TO 2.0 FOR NON-HYDROELECTRIC QFS

Q. WHAT IS THE COMPANIES' POSITION ON THE PERFORMANCE ADJUSTMENT FACTOR?

A. The Companies are proposing that a PAF of 1.05 should be applied for all QFs on a going forward basis, except that existing small hydroelectric QFs should continue to receive a PAF of 2.0.

Q. SHOULD THE COMMISSION INCREASE THE PAF TO 2.0 FOR NON-HYDROELECTRIC QFs?

A. No. The PAF is a multiplier applied to the avoided capacity rates paid to QFs to allow a QF to experience a reasonable amount of outage time without being penalized from the standpoint of the capacity payments it receives. The PAF was established because QFs only receive capacity payments for power that they deliver during on-peak hours. Because all generation is subject to outages, it is reasonable to assume that QFs, like other generation, will not run during 100% of on-peak hours. This rationale may justify a PAF of 1.05, but it does not warrant a PAF of 2.0. In effect a PAF of 2.0 would allow a QF with a 1 MW capacity that can only operate during 50% of onpeak hours, to be compensated as if it is delivering 1 MW of capacity value. Such result overpays the QF for the capacity it is actually delivering and allowing the purchasing utility to avoid.

Moreover, increasing the PAF to 2.0 for non-hydroelectric QFs would be inconsistent with the General Assembly's intent in passing Senate Bill 3. As I have discussed at length, although Senate Bill 3 is designed to encourage renewable generation by establishing a REPS for the state's utilities, the General Assembly also made clear that there should be limits to the costs incurred pursuing that policy. In fact, the provisions of Senate Bill 3 that limit the costs incurred by utilities, and ultimately recovered from their customers, focus specifically on costs incurred in excess of the utilities' avoided costs. It would be inconsistent with the self-contained cost control framework of Senate Bill 3, which uses utility avoided cost as a key component, to increase the avoided capacity rates paid to solar and wind QFs by 67%. Accordingly, the Companies do not believe that the REPS framework and policies enacted through Senate Bill 3 support the proposition that the Commission should increase avoided cost payments to solar and wind QFs by increasing the PAF for those facilities to 2.0 for non-hydroelectric .

Q. WHAT EFFECT WOULD INCREASING THE PAF TO 2.0 HAVE ON CUSTOMERS?

A. Obviously, increasing the PAF to 2.0 for non-hydroelectric QFs would increase the costs that customers bear. In Docket No. E-100, Sub 136, I testified that such an increase in the PAF could cost customers an incremental $150 million for every 1,000 MW of new solar QF capacity over the life of 15-year PPAs. I have not had that analysis updated for this docket, but I believe that estimate is conservative given that the analysis was based on the Companies' proposed avoided capacity cost rates, which were lower than the rates ultimately approved by the Commission.

Q. ONE ARGUMENT FOR THE INCREASED PAF IS THAT IT PUTS SOLAR QFS ON PAR WITH THE COMPANIES, IN THAT THE COMPANIES RECOVER 100% OF THEIR CAPITAL COSTS. WHAT IS YOUR RESPONSE TO THIS ARGUMENT?

A. I do not believe that this argument is logical, relevant, or appropriate. The underlying assumption of the argument is that a public utility's regulated cost recovery mechanism is comparable to PURPA's avoided cost framework. For several reasons, this is not the case.

First, if a public utility installs a solar facility, it earns nothing on the capital it has invested in that plant (i.e., receives no incremental revenue) unless and until the utility has a rate case and the Commission determines that the capital was prudently incurred and should be included in rate base. Conversely, a solar QF is guaranteed compensation through avoided cost rates immediately upon commencing commercial operation.

Second, a public utility only earns a Commission-established return on the capital invested in its solar facility. Also, in the case of a solar facility, the utility receives almost no "energy" payments from customers for a solar facility because it incurs no fuel costs and very little in operating expenses. A solar QF, on the other hand, receives avoided cost payments that are tied to the purchasing utility's costs, not the cost that the developer spent to build the QF. Moreover, the QF receives payments for avoided capacity costs and avoided energy costs. Essentially, the entirety of both types of payments contributes in large part to the QF's recovery of and return on its capital investment because a solar QF has essentially no "energy" costs (i.e., fuel costs) to defray.

Third, if and to the extent a public utility receives incentives or subsidies for constructing a solar facility, such as tax incentives, such benefits ultimately are flowed through to customers because they lower the utility's revenue requirement for rate making purposes. If a solar QF receives these types of benefits, the developer retains the benefits, which further enhances its bottom line and contributes to its return on the capital it has invested.

Finally, a utility's recovery of the capital it invests in utility plant is based on the rate of return established by the Commission. Currently, such returns on equity tend to be in the 10-11% range and overall rate of return tends to be in the 8% range. A solar QF is not subject to such regulation and may earn a substantially higher return. Of course, unlike public utilities, solar QF developers are not required to make their financial results public. Consequently, there is no way to determine if a solar QF is making 10%, 20% or 30% returns.

In summary, the mechanisms under which public utilities and QFs are compensated for investing capital are entirely different. Consequently, it is illogical to manipulate the avoided capacity payments that a QF receives to try to put the payments "on par" with regulated rate making. It is particularly unreasonable to do so because inflating the avoided capacity payments to achieve such alleged parity ignores the fact that QFs receive other revenue streams in the form of avoided energy payments and various incentives that contribute to the QFs' return on its capital investment.

Q. IS THERE A SOUND POLICY BASIS UNDER PURPA FOR INCREASING THE PAF TO 2.0 FOR NON-HYDROELECTRIC QFS?

A. No. The parties advocating for a 2.0 PAF for these QFs focus primarily on providing the higher PAF for solar QFs. NC WARN witness LaPlaca argues that since solar has particularly beneficial attributes, solar QFs should receive a PAF of 2.0.[52] EDF witness Munns argues that a 2.0 PAF should be used as a proxy for the cost of complying with environmental requirements that may be imposed in

[52] NC WARN witness LaPlaca Direct, at 17.

the future until such requirements are actually implemented and the real cost of compliance can be calculated.[53] I have already explained why factors such as the ones relied upon by witnesses LaPlaca and Munns are not appropriate considerations for establishing avoided cost rates under PURP**A.** Even if they were, however, it would be improper for the Commission to assume that inflating avoided capacity payments by using a 2.0 PAF is a reasonable proxy for such factors. Avoided cost rates must be based on real costs that a utility avoids by purchasing power from a QF. Simply assuming the existence of such cost and then doubling avoided capacity rates would be completely inconsistent with the intent of PURPA's avoided cost requirements.

VIII. <u>CONCLUSION</u>

Q. BASED ON THE TESTIMONY FILED TO DATE BY OTHER INTERVENORS, DO YOU HAVE ANY CHANGES IN YOUR ORIGINAL RECOMMENDATIONS INCLUDED WITHIN YOUR DIRECT TESTIMONY FILED IN THIS DOCKET?

A. No, I do not have changes to the recommendations included my direct testimony.

Q. DO YOU BELIEVE THE COMPANIES' RECOMMENDATIONS WILL ALLOW THEM TO MOST ACCURATELY CAPTURE THEIR FULL AVOIDED COSTS FOR PURPOSES OF APPROPRIATELY COMPENSATING QFS?

[53] EDF witness Munns Direct at 7.

A. Yes, I believe the recommendations allow for an accurate representation of the utilities' avoided cost and allow for the implementation of PURPA as the law intended.

Q. DOES THIS CONCLUDE YOUR SUPPLEMENTAL DIRECT TESTIMONY?

A. Yes, it does.